Initial Comments of the Electricity Oversight Board Regarding the Foundational Reports to the Integrated Energy Policy Report

The Electricity Oversight Board (EOB) has the reviewed the recently circulated "staff paper"[1] and five "staff draft reports"[2] intended to underpin the Integrated Energy Policy Report (IEPR) and has identified some areas of concern regarding elements of these documents. The most significant concerns are discussed generally below, followed by identification of specific statements or conclusions of concern in the individual documents.

General concerns with assumptions and conclusions currently reflected in IEPR foundational documents.

- It is inappropriate to use the level of installed generation capacity as a proxy to predict either the competitiveness of market performance or real-time operating reliability.

  In numerous places, the reports assert that adequate generation capacity assures reliably delivered and competitively priced energy. This connection is carried further by stating that the CEC staff has concluded that adequate capacity has now been installed to ensure reliable and competitively priced power through 2005. Installed generation capacity should not be used as a direct proxy for either market performance or operating reliability. A conclusion that adequate capacity is installed to equal the forecast demand plus operating reserves should not by any means be taken to indicate that wholesale electricity markets will function competitively and produce reasonable prices.

  Adequate installed generation capacity is one of a number of factors needed for operating reliability. It is not the only critical link in the chain. Most of the reliability failures in recent years happened at load levels that did not strain installed capacity but related more to which plants were online, which were offering their energy, and a variety of problems with market behavior, power management systems, conflicts between scheduling rules and contract forms, and a other esoteric problems. The EOB has worked in recent months to try to address reliability problems that have

[1] Natural Gas Supply and Infrastructure Assessment

[2] Preliminary Electricity and Natural Gas Infrastructure Assumptions, California Energy Demand 2003-2013 Forecast, Comparative Cost of Central Station Electricity Generation Technologies, California Investor-Owned Utilities Retail Electricity Price Outlook 2003-2013, California Municipal Utilities Retail Electricity Price Outlook 2003-2013

occurred in the middle of the night during low-load months where reserve margins were ample.

Under current circumstances, it is speculative to conclude that reliability is assured. Market rules remain in flux, the future of mitigation mechanisms that have stabilized the system since mid-2001 is in jeopardy, as is the stability of many of the enterprises that comprise the merchant marketplace. In the absence of stable market with adequate market controls, it is probably only safe to assume reliability to the extent that load-serving entities have guaranteed ability to dispatch dedicated resources to serve their own load, either using their own generation or firm contractual rights.

Similarly, competitive market outcomes depend on sellers' market behavior and market rules and are not well predicted by installed capacity alone. While the depth of the market can be expected to affect the level of competition, so will market concentration, market rules, and other factors that are much harder to analyze (such as individual companies' hedge positions at any given time). While several analysts have attempted to correlate market competitiveness with the level of bid super-sufficiency, the EOB considers these efforts unreliable. While it may be reasonable to generalize that lower reserve margins detract from the competitiveness of short-term markets, the EOB urges against assuming that any known reserve level of installed capacity should be expected to produce competitive prices absent a number of other needed elements not addressed in the reports.

Deriving conclusions of assured operating reliability and competitive market prices from an assessment of adequate installed generation capacity may subject the State to the risk of real-time blackouts and recurrence of exorbitant prices.

- <u>The conclusion that spot-market prices and price caps are driving factors in generation investment is inaccurate</u>.

The Infrastructure Report appears to rely in various places on a premise that high spot-market prices must be allowed in order to foster investment in generation and that spot price caps will retard needed investment. The EOB believes this premise is inaccurate and should be removed. In the current (nationwide) investment environment, generation infrastructure investment is driven primarily by long-term contracts, not by projections of spot prices or spot-market caps.

The recent experience of the EOB in dealing with both energy companies and financing institutions leads to the opinion that very little generation will be financed "on spec" against anticipated spot-market sales regardless of whether price caps exist. Generation development is likely to proceed where it is supported by arrangements (long-term contracts or dedicated customers) against which it is possible to firmly project the recovery of a majority of plant capitalization. In the near term, California's energy policy should not rely on "the market" to develop generation except to the extent that the state-regulated procurement processes may make specific solicitations to the market to develop facilities under contract.

- It is unwise to rely on forward price projections that assume fully competitive pricing.

  It appears in places that the wholesale power price predictions outlined in the various draft reports were generated from production costs assuming the existence of fully competitive market behavior. If this was the basis for price forecasts, the EOB is very concerned about any assumption that the market will actually produce those prices. If this is not the case, it is unclear what assumptions regarding market performance were used. (There is a statement that the Marketsym model has simulated bidding behavior, but it is also stated that the CEC staff has concluded that capacity additions will produce competitive prices.)

  The EOB has opinions on the feasibility of projecting forward energy prices under theoretical perfect competition and also of projecting a zone around these prices that would define legally allowable outcomes under the Federal Power Act. These issues are the subject of litigation that makes it somewhat awkward to discuss them at length in these comments, and doing so is unnecessary to the point of this comment. If one makes a number of assumptions about available resources, fuel costs and similar factors, it is possible to make some projections about what energy prices should be in a highly competitive environment. There are large risks in assuming that such projections will be reflected in real prices in the years ahead.

  The EOB believes that western energy markets remain highly susceptible to non-competitive outcomes. The State faces a substantial fight to keep in place market rules that will maintain predictable bounds on market outcomes. Behavior consistent with fully competitive markets should not be assumed in the near future. Consequently, the cost projections related to performance of electricity spot markets appear uncomfortably optimistic. Based on these projections, the reports appear to conclude that utilities should and will make significant spot market purchases as a least-cost procurement strategy. The EOB believes that spot market risks remain very high and that, for risk management reasons, the spot market should not be relied on for any significant amount of bulk energy.

Specific Comments on Individual Reports

The EOB also has comments specific to each report as well as attachments which identify text exemplifying the concerns highlighted below.

<u>Preliminary Electricity and Natural Gas Infrastructure Assumptions</u>

This report contains conclusions regarding generation and transmission capacity, market prices and market influences which raise significant concerns. These are as follows:

- <u>Sufficient electricity generation capacity has been added to the west to assure reliable, competitively priced electricity through 2005</u>.

  It is the EOB's position that adequate capacity is necessary to provision of reliable electric service and contributes to competitive prices but that capacity adequacy alone cannot be taken as ensuring reliability or competitive prices. Various market design proposals are aimed at preventing the various gaming and withholding practices of market participants because capacity alone cannot protect consumers from the price gouging and curtailments witnessed in 2000-2001. This conclusion equating capacity with reliability and a competitive price outcome, which is reiterated in various forms throughout the document, is invalid and should be removed.

- <u>Low energy prices and surplus capacity represent major impediments to the construction of new generation, particularly generation projects currently under construction.</u>

  These two conclusions underlie many statements throughout the document, particularly for years 2003-2007. The basis for the conclusion that "surplus" or "excess" capacity exists through 2007 is not clear, particularly since assumptions regarding electricity demand are necessary (but not stated) in order to conclude that a particular level of capacity is "excess".

  In addition, the report makes broad and unsubstantiated conclusions such as "… regulatory uncertainty continues to unsettle both developers and financial markets…*in the absence of very high spot market prices, these uncertainties must be resolved before a substantial amount of new capacity is brought into the market*." (pg 10, emphasis added.) The EOB strongly disagrees with both the statement and the implied underlying assumptions, including that spot market prices govern generation construction decisions. It is the position of the EOB that current or future predictions of spot market prices will not be the driving force behind investments in generation capacity. Rather the investment community is likely to require that developers exhibit the ability to recover costs with firm revenue projections associated with forward contracts.

- Entities with load serving obligations should be responsible for resource adequacy while government intervention in the market will likely dampen the investment cycle. Nevertheless, it is assumed that there will be sufficient capacity to reliably meet load at a reasonable price, however that is to be achieved.

  The EOB fully supports the statement that entities with load serving obligations should be responsible for resource adequacy. However, while the report acknowledges that tremendous uncertainty exists regarding projections for years 2007-2013, critical underlying assumptions explained in the workshop may produce a misleading result by assuming away critical uncertainties facing the state. The problematic assumptions are the following:

  - Assume that the combination of generation additions and retirements provide the necessary level of reliability.
  - Assume that if the market does not yield desired amount of capacity for reliability, some form of regulatory oversight and intervention will assure it. Assume the state will not be caught in a "short" position during the period in question.
  - Assume that overall reliability is adequately indicated by reserve margins.

  By equating capacity adequacy with reliability and then assuming that capacity will be kept adequate, the resulting determination that reliability will be maintained becomes a forgone conclusion and is of little value. The state must act very deliberately in order to maintain adequate capacity. This need should be highlighted in developing policy and not assumed. Capacity adequacy and reserve margins affect reliability but should not be equated with reliability. There were instances during 2000 – 2001 where periods of load curtailment were not caused by a capacity shortage; rather they were the result of generators refusing to provide power dispatched by the ISO. In addition, the statements and assumptions regarding government intervention are confusing (particularly when taken together with the conclusion also included that government intervention will dampen generation development).

California Energy Demand 2003-2013 Forecast

The EOB does not engage in demand forecasting and consequently limits its comments on this subject. We do note that this report incorporates conclusions regarding the electricity costs from the IOU Retail Price Report. Neither report sufficiently describes how future spot market prices were estimated for the EOB to have comfort with the cost conclusions.

California Investor-Owned Utilities Retail Electricity Price Outlook 2003-2013 and California Municipal Utilities Retail Electricity Price Outlook 2003-2013

For both of these reports, the EOB reiterates its concern that retail prices are forecast without adequate discussion of the assumptions and methods used to predict wholesale prices and costs.

Although the IOU Retail Price Report includes a description of the process for generating the current year forecast, it does not indicate what assumptions are used to predict rate component changes over time.

It is not clear to the EOB why a state projection of municipal retail rates is important. Assuming it is necessary, the treatment of future capital costs expenditures is not presented or apparently considered in the Municipal Utilities Retail Price Report.

Comparative Cost of California Central Station Electricity Generation Technologies

This report does not appear to provide a full and comparable comparison of the total cost of the various technologies considered. Specifically:

- The costs of employees, maintenance, permitting and interconnection are considered for some technologies and not for others.
- No explanation or justification is given for the significant variation in per-acre land costs used for different technologies (from $5,000 to $100,000 per acre).
- Some of the operating parameter assumptions appear unrealistic (i.e., heat rates, number of annual starts and capacity factors).
- The escalation rate for Labor and Operation and Maintenance (0.5percent) appears low.

In addition, the report includes overly broad statements that may be inaccurate or misleading. Specifically:

- Under "Applicability", page 4, the third paragraph seems to imply that often contract prices have no correlation to the generation costs of a particular unit. While this might be true if a party is selling system power from a portfolio, the statement should be clarified to note that a load serving entity participating in a competitive market for long-term power supplies should be incorporating a reasonable prediction of future generation costs into its negotiation of contract prices.

- Also on page 4, the fourth paragraph states that gas-fired fuel generators add risk premiums to their costs in fixed-price power contracts because they bear the fuel-price risk. This statement should be modified because the treatment of risk allocation and the conclusion regarding a risk premium is inaccurate and misleading. Entering into fixed-price electricity contracts provides a level certainty and reduces risk for both the buyer (cost risk) and generator (revenue risk). The seller is capable of avoiding or minimizing their own cost uncertainty by entering into hedge contracts to lock in fuel costs. The allocation of risks is priced on both sides of a transaction. It is not proper to characterize a fixed commodity price as including a "risk premium." This is a term of art that refers to a different circumstance than what is being discussed in the report, one in which a transaction carries a higher risk than commercially typical (such as, for instance, a high probability of default by the buyer). As it appears in the report, the use of the term "risk premium" suggests that consumers will pay an inherently higher price if their bulk power is obtained through fixed unit price bulk energy contracts than they would if the buyers always carried the full fuel price risk. This is incorrect.

Attachment 1: Specific Text Notations

The passages highlighted in bold below are sources of concern. The EOB believes some of these are incorrect or misleading as presented. Several others may require additional explanation to support them or be subject to misinterpretation in their present form.

Preliminary Electricity and Natural Gas Infrastructure Assumptions Report –

1) Pg i

The Energy Commission staff concludes that sufficient electricity generation capacity has been added in the west to assure reliable, competitively priced electricity through 2005, based on analysis of electricity generation additions in the Western Electricity Coordinating Council area from 2000 to 2003

2) Natural Gas Infrastructure, Pg ii

This report does not offer any conclusions regarding the need for additional gas infrastructure **because the type, size and location will be determined, in large part, by the location of new power plants**.

3) Chapter 2 – Electricity Generation Infrastructure, Pg 3

The past three years have witnessed a substantial increase in electrical generation capacity in California and the remainder of the West. We have moved from a condition of shortage –with price spikes, voluntary load curtailments, and rotating outages – to one of sufficiency **if not, for the moment, surplus**.

4) Chapter 2 – Electricity Generation Infrastructure, Pg 3

A summary of wholesale spot market prices during the past eighteen months contributes **to the conclusion that enough capacity has been added in the west to assure reliability and competitively-priced electricity during 2003 – 2005.**

5) Changes in Supply and Demand, 2000-2003 California Pg 4

...the net effect of changes in supply and demand in California during 1999 -2003 has been a **substantial increase in the state's reserve margin.**

(Note: It is not clear how table 2-2 substantiates claim. It shows peak load for the year 1999 to 2003 and nets additions. To identify a reserve margin we would need to see total capacity compared to peak load rather than just capacity increases.)

6) Changes in Supply and Demand, 2000-2003, Remainder of WECC, Pg 5

> **One of the proximate causes of the energy crisis of 2000 – 2001 was a gradual deterioration of the supply – demand conditions during the 1990s in both the Northwest and Southwest**. Despite substantial growth in the demand for electricity during the decade (2.1 percent annually in the Northwest, 3.8 percent in the Southwest (1)), little new generation capacity was added; both areas relied on existing surpluses. By 2000, the export potential of these regions was well below what California needed to offset its own declining reserve margin. Reserve margins have increased substantially in the Northwest and Southwest since 2000, as Table 2-3 indicates.
>
> (Note: It is not clear how table 2-3 substantiates claim. It shows peak load for the year 1999 to 2003 and nets additions. To identify a reserve margin we would need to see total capacity compared to peak load rather than just capacity increases.)

7) Current Conditions, pg 6

> **Improvements in the supply-demand balance in California and throughout the West have contributed to a substantial reduction in spot market and forward prices for electricity (see Figure 2-1). Increases in these prices during the past three months are not due to shortages in electricity generation capacity and/or the concomitant ability of generators to manipulate wholesale markets, but higher prices for natural gas.** The causes of the recent run-up in natural gas prices are discussed in Chapter 4 of this report.

(The EOB is in the process of investigating several price aberrations that have occurred in the last two months and cannot agree that they are necessarily due solely to rise in underlying fuel prices.)

8) Construction Delays, Cancellations and Debt, pg 8-9

> The large number of cancellations has been attributed in part to the deterioration of the balance sheets of the major power plant developers. While their stock prices have plummeted during the past year, they have accumulated a large amount of debt, much of it short-term (due in 2003 and early 2004)**. Debt service has been rendered difficult by the collapse of electricity prices since early 2001, all the more so as the unrealistically high revenue streams projected from newly built plants were often leveraged: used to debt-finance additional projects which have yet to be completed. This has restricted developers' access to both the additional equity capital and debt needed to complete construction.** Given the improvement in the supply-demand balance in both California and the remainder of the West, these delays and cancellations do not pose an immediate threat to the reliable delivery of electricity in the West. Current supplies, and those conservatively anticipated to come on line by the summer of 2003, are sufficient, even under 1-in-10 year peak summer temperatures, to meet demand during

2003 and 2004**. Supply adequacy also means that Californians are less likely to face high wholesale prices during periods of peak demand**. While Energy Commission staff recognizes the role that credit issues can play in delaying projects under development and securing the capital needed to finance additional construction, **staff believes that low forward prices and regulatory uncertainty are the primary impediments to the completion of unfinished projects**. Staff does not believe that the debt overhang poses a threat to the development of new generation as it is needed during the next three to five years. There is no reason to believe that the capacity market will not 'shake out,' with new sources of capital stepping forward to reliquify the market when it is profitable to do so. This will take the form of financially healthy players, perhaps new to investment in the power generation sector, buying up existing projects at 'fire sale' prices or financing new ones. This is slowly beginning to happen already. An acceleration of this process will take place when expected revenue streams from new projects are both high enough and stable enough to attract financing.

9) Projections, 2004 – 2006, pg 9-10

While Energy Commission staff have carefully monitored the progress of development projects in California and the remainder of the West, projections of infrastructure development during 2004 – 2006 must acknowledge a great deal of uncertainty. Decisions regarding capacity additions, retirements and transmission upgrades are, more often than not, being delayed pending developments in both the electricity and natural gas markets and various regulatory arenas.

Futures prices for 2004 do not appear to be sufficient to encourage the rapid completion of projects under construction. As of this writing, forward prices for 2004 delivery yield sparkspreads[3] in the $12 - $15 range, albeit in a very illiquid market. At the high end, this is enough to allow for debt service and an adequate return to equity in a stable setting, but several factors mitigate against new capacity coming on-line quickly.

First, as noted above, a substantial share of the energy needed to meet loads has already been procured. During shoulder and off-peak hours, the IOUs are frequently long, indicating that new baseload capacity may have a limited market in California for its output in the near term. The requirements of the renewable portfolio standard (RPS), as well as contracts entered into under CPUC procurement proceedings during 2002 and 2003, will further reduce the market for non-renewable baseload generation in the state. These facts, combined with the presence of excess capacity, indicate that, in the absence of a contract for its output, (continued on pg 10) a new combined cycle will be hard pressed to operate at the capacity factor necessary to make current prices attractive.

Second, regulatory uncertainty continues to unsettle both developers and the financial markets to which they turn for capital. Questions related to market price caps, resource adequacy requirements, transmission interconnection and pricing, possible State assumption of partial responsibility for new generation, CPUC activity with respect to procurement and reasonableness determination, *etc*, remain unanswered. **In the absence of very high spot market prices, these uncertainties must be resolved before a substantial amount of new capacity is brought to the market.**

10) projections, 2007-2013, Pg 15

Whatever uncertainty exists surrounding changes in the energy infrastructure during 2004 –2006 are multiplied ten-fold for the years that follow. While we have survived the calamity of 2000 – 2001, we have yet to erect a new market structure that will provide reliable energy at reasonable and stable prices. There is general agreement that those entities with load serving obligations should be responsible for resource adequacy, but there is substantial disagreement regarding what steps they should or must take to meet this responsibility, and who will ensure that they take them. Government intervention in the market, if successful, will likely dampen the investment cycle, eliminating periods during which there is insufficient capacity to reliably meet loads at a reasonable price. The baseline "resource plan" for 2007- 2013 discussed below does not require assumptions about the precise role that the state will play in the energy markets during the coming decade. **It only assumes that there will be sufficient capacity to reliably meet load at a reasonable price, however that is to be achieved.** The resource plan is only a forecast to the extent that it assumes that whatever regulatory policies are adopted; they ensure timely construction of an adequate amount of capacity. Realizing that success in this regard is by no means certain, simulating and assessing a less optimistic future is suggested in the form of a separate scenario.

(Note: shouldn't the assumption here the desired outcome of this process, rather than the input assumption?)

11) Electricity Transmission Infrastructure, Pg ii

By contrast**,** transmission system additions, those that would allow large amounts of power to move from one region to another, have not kept pace with recent electricity generation resource additions. **The lack of sufficient bulk electricity transmission capacity makes it difficult for grid operators to fully capitalize on the system-wide economic benefits of recent resource additions in and around California….**

12) Chapter 1 Introduction, Pg 1

> Use of MARKEYSYM as the principal assessment tool for the electricity market…using information on the operating characteristics of individual power plants and transmission grid, fuel prices, the **bidding behavior of power plant operators**. MARKETSYM produces hourly estimates of plant outage, fuel use, and emissions, as well as transmission line usage, congestion costs and wholesale prices.

13) Chapter 1 Introduction, Pg 2

> The flow of the report is based on the **assumption that electricity demand is the driving force behind future electricity generation, electricity transmission, and natural gas improvements and additions. The need for additional electricity supplies determines when, and where, new electricity generation infrastructure will be built. The location of the new electricity generation infrastructure then dictates whether new transmission projects must be undertaken to support it, or if the new power plant relieves current electricity transmission constraints.** Finally, the amount and location of electricity generation will determine how much natural gas infrastructure must be added to support it, as natural gas has become the marginal fuel source for new power plants in the United States.

(This seems to assume that the location of load centers will primarily drive the location of new generation. The EOB does not understand the basis for this conclusion. The EOB thinks it is likely that, absent a contractual obligation to locate generation in a particular place, generators will locate where they have the most versatile fuel supplies, the most favorable fuel tariffs, and the greatest access to multiple markets (such as relatively certain transmission access to recognized trading hubs).

14) Chapter 2 – Electricity Generation Infrastructure, Current Conditions: Pg 8

> …**IOU spot market exposure can be expected to be less than 2000 MW during all but a handful of hours during the next two years.**

15) Projections, 2004-2006, California, Additions and Retirements, Pg 10

> **Staff feels that new construction in California may be limited to a handful of plants during 2004 – 2006. Table 2-6** lists the plants that are to be added or retired in the staff's simulations of the WECC, yielding a net increase in thermal capacity of 1126 MW. This is roughly 40 percent of the load growth anticipated during this period. The Calpine facilities are two of three for which the state has "step in" rights, which allow it to complete construction of the facilities and bring them on line if the developer fails to meet construction milestones. **Staff does not assume the state's agreement with Calpine assures their completion.**

16) Transmission Upgrades, pg 12-13

> **The simulation model used by Energy Commission staff to assess market conditions divides California into nine transmission areas** (see **Appendix A, Figure A-1).[** Four upgrades that affect the transfer capability between these areas are assumed to occur during 2004 – 2006. The transfer capability from SCE to ZP26 is increased by 400 MW in October 2003. Path 15 (connecting NP15 and ZP26) is upgraded in January 2005 (an additional 1500 MW from [continued on pg 13] south to north, 1135 MW from north to south) as of January 2005. Upgrade of the Jefferson- Martin line increases the ability to import energy into San Francisco from 700 to 1100 MW as of January 2006. Finally, a Miguel – Mission upgrade increases the transfer capability from Miguel into San Diego by 560 MW in January 2005.**

(Note**:** Figure A-1 does not clearly identify nine areas. Should be revised to make areas more explicit. Also: Should identify the generation resource assumptions used in the simulation model.)

17) Thermal Additions, Pg 16

> **Energy Commission staff propose adding new capacity for simulation purposes during 2007 – 2013 to maintain reserve margins at those levels observed in 1998 – 1999** (see Table 2-10). **This period is chosen as it arguably reflects reserve margins that are high enough to ensure reliability and allow for competitive wholesale spot markets, but low enough to yield prices that, along with other available sources of revenue (*e.g.*, ancillary services, capacity payments), provide an adequate return to investment. This reserve margin is plausible across various assumptions regarding the extent to which the state and the federal government intervene in the capacity and energy markets.**

18) Projections, 2007-2013; Retirements, Pg 17

> Given the above assumptions regarding additions and retirements in 2004 - 2006, 2007 will arrive with reserve margins in the WECC well above those of 2000 – 2001. It is possible, of course, that some of the capacity assumed to come on-line in 2004 – 2006 will not do so, and all but certain that some existing, older plants, will retire in 2007 - 2013. **Recent prices, and those that have recently been forecasted for 2003 – 2005 are not high enough alone to sustain existing steam turbines with heat rates in the 9,500 – 11,000 Btu/kWh range. Caps on wholesale prices call into question the profitability of peaking units that lack capacity contracts. Should these types of plants retire *en masse*, reserve margins would fall, spot market prices would rise, and, in a worst-case scenario, both the competitiveness of the market and system reliability would be compromised.**

> The "retirement decision" is a complex one, requiring consideration of numerous variables. These include qualitative estimates (e.g., regulatory policy), proprietary data (alternative uses of the land or investment opportunities for the owner), and knowledge of the decisionmaker's expectations regarding future conditions. It is further complicated by the possibility of keeping the plant in one of several states of "stand-by." While a large share of the state's capacity is aged and much of that will become increasingly non-competitive, it should be noted that a not-insignificant portion of that capacity does not rely on the market alone for revenue. Many of these units have RMR contracts and will not be retired unless and until new generation (or transmission) replaces these facilities. Several have long-term contracts with an IOU. **Accordingly, Energy Commission staff, in designing a baseline "resource plan," hesitate to assume the retirement of specific facilities. In fact, the figures in Table 2-10 assume that the San Diego area's South Bay facility will be the only major retirement in California during 2007 – 2013.**

(The first bold passage would appear to render the second an imprudent assumption)

19) Pg 17-18

> **From a simulation modeling perspective, when the system is characterized by surplus capacity the decision to retire existing facilities, short of doing so to the point of threatening reliability, is arguably not a crucial matter.** Previous simulations have indicated that existing steam turbines, which have traditionally met baseload demand, will become marginalized increasingly used only in the summer during periods of high demand. This function is shared with newer "peaking" units, plants that are as efficient as the steam turbines (or more so) and can be brought up to full load more quickly. Effectively, the "supply curve," even on weekdays during the summer, becomes very flat over a broad range, with the least efficient peakers (13,000 Btu/kWh) being seldom if ever called upon. Under these circumstances, estimates of prices, fuel use, emissions, *etc*. are insensitive to assumptions about the retirement of (a moderate amount of) older capacity, save for during a handful of hours of the year.
>
> We do not mean to minimize the significance of the system's ability to meet loads during these hours, nor of the potentially high prices that might prevail. Energy Commission staff will run a "low addition, high retirement" scenario to determine the impact of a lower reserve margin on system conditions during hours of very high demand, but tentatively propose not to retire existing facilities in California (other than South Bay) during 2007 – 2013 in the baseline study. Comments on this proposal are actively solicited.